Behind-the-Meter Compressed Air Energy Storage Feasibility and Applications

Chioma C. Anierobi, Kankar Bhattacharya, Claudio A. Canizares
Department of Electrical and Computer Engineering
University of Waterloo, Canada
{canierob, kankar.bhattacharya, ccanizar}@uwaterloo.ca

***Abstract*—In this paper, the operations model of a behind-the-meter Small Scale Compressed Air Energy Storage (SS-CAES) facility is developed for an industrial customer with existing wells/caverns that can be re-purposed for air storage. The operations model seeks to minimize the electricity costs of the industrial customer, while determining the energy output and the corresponding charging and discharging decisions of the SS-CAES system. In order to examine the financial viability of a practical behind-the-meter SS-CAES facility, an economic analysis is carried out using real data of an industrial customer based in Ontario, Canada. Key parameters such as life cycle, CAES capacity and capital cost, and electricity price are considered for carrying out a sensitivity analysis, with the results showing that SS-CAES is economically viable for the current Ontario electricity tariff rate structure. The low capital cost of a SS-CAES project with a re-purposed storage cavern, and the high Global Adjustment charges levied in Ontario are shown to be a key determining factors for the economic feasibility of deployment of SS-CAES in Ontario.**

***Index Terms*—Behind-the-meter, compressed air energy storage, demand charge, electricity cost reduction, load management.**

NOMENCLATURE

Indices

h	Index for hours, $h = 1, 2, ..., 24$
d	Index for days, $d = 1, 2, ..., 365$
m	Index for months, $m = 1, 2, ..., 12$
y	Index for years, $y = 1, 2, ..., N$

Parameters

$CAPEX$	Capital cost of CAES [$]
$Eini$	Initial air storage level $[MWh]$
E^{max}	Maximun energy capacity of the CAES $[MWh]$
E^{min}	Minimum allowed level of air storage $[MWh]$
$Ep_{d,h}$	Hourly Ontario Energy Price $[\$/MWh]$
$FOMC$	Fixed O&M cost of CAES $[\%]$
N	Project life $[year]$
MDT	Downtime for maintenance $[\%]$
$OND_{d,h}$	Ontario system-wide demand at 5cp $[MW]$
P^{min}_{comp}	Minimum allowed charging power $[MW]$
P^{max}_{comp}	Maximum allowed charging power $[MW]$
$PD_{d,h}$	Hourly demand $[MW]$
P^{min}_{exp}	Minimum allowed discharging power $[MW]$
P^{max}_{exp}	Maximum allowed discharging power $[MW]$
$P^{gridmax}_{d,h}$	Power supply from the grid $[MW]$
$OMGA_m$	Total Ontario Monthly Global Adjustment [$]
$VOMC_{comp}$	Variable O&M cost of Compressor $[\$/MWh]$
$VOMC_{exp}$	Variable O&M cost of Expander $[\$/MWh]$
η_{comp} / η_{exp}	Compressor/Expander efficiency $[\%]$

Variables

$E_{d,h}$	Energy level at each time step $[MWh]$
EC^{CAES}	Total annual energy cost of industrial customer with CAES [$]
EC^{NoCAES}	Total annual energy cost of industrial customer without CAES [$]
GA^{CAES}	Total annual Global Adjustment charge of industrial customer with CAES [$]
GA^{NoCAES}	Total annual Global Adjustment charge of industrial customer without CAES [$]
$P^{Ch}_{d,h}$	Power consumption by CAES facility in charging mode [MW]
$P^{DCh}_{d,h}$	Power generation by CAES facility in discharging mode [MW]
$P^{grid}_{d,h}$	Power drawn by the industrial customer from the grid $[MW]$
S_y	Total annual savings with CAES facility [$]
$SFOMC$	Yearly fixed O&M cost of CAES [$]
$SVOMC$	Total annual CAES variable O&M cost [$]
TC^{CAES}	Total annual electricity cost of industrial customer with CAES [$]
TC^{NoCAES}	Total annual electricity cost of industrial customer without CAES [$]
$U^{Ch}_{d,h}$	CAES facility in charging mode [0: OFF and 1: ON]
$U^{DCh}_{d,h}$	CAES facility in discharging mode [0: OFF and 1: ON]

I. INTRODUCTION

Commercial and Industrial (C&I) customers in many jurisdictions are not only charged for their energy consumption but also for the power they draw from the grid at peak hours [1]. For this category of customers in Ontario Canada, the peak demand charge has been increasing, accounting

This work has been carried out with the support of the Natural Science and Engineering Research Council of Canada (NSERC), CRDPJ 477323-14, and the Ontario Centres of Excellence (OCE). The input provided by NRStor and Compass Energy are gratefully acknowledged

for a significant part of the overall operating cost of these businesses. However, C&I customers who participate in Ontario's Industrial Conversation Initiative (ICI) program can save significantly on their electricity cost, if they reduce their demand during the system peak load hours [2]. However, in an industrial facility load management can be very challenging, especially when faced with production constraints in high energy-sensitive production lines, where short interruptions are not feasible.

Behind-the-meter energy storage can reduce the industrial customers power demand from the grid without interrupting its usual daily activities. In this context, Small Scale Compressed Air Energy Storage (SS-CAES) is a possible option for managing the load of a large customer; however, in [3] the authors argue that CAES is not suitable for small-scale applications because of the sheer size of installations and associated costs. On the other hand, repurposing the existing wells/caverns may significantly reduce the SS-CAES capital cost [4], but this argument requires detailed economic studies for validation. Therefore, investigating the feasibility and economic viability of SS-CAES for a real industrial customer with available empty wells/caverns for air storage, to defray the high peak-power electricity prices of Ontario, is the focus of this paper that is based on [5]. Hence, a mathematical model that coordinates the operation of an industrial customer's facility, equipped with a behind-the-meter SS-CAES, is presented here. The optimization model takes as inputs, the storage performance characteristics (e.g., efficiency, energy and power limits), customer load profile, and electricity prices to determine the minimum electricity cost operation, charging/discharging decisions of the SS-CAES, and energy purchase/consumption schedules of the customer, over a given time horizon. Finally, since SS-CAES projects are at the development stage, economic uncertainties are relatively high, and therefore, an economic and sensitivity analyses of the interactions between financial viability of such a project and some key parameters (e.g., life cycles, SS-CAES capital cost, electricity prices) that would influence an investment viability are carried out.

The rest of the paper is organized as follows: Section II presents the relevant background on CAES and Ontario's electricity pricing. Section III presents the mathematical model for the operation of a SS-CAES facility installed at a customer's premises for load management. Section IV presents and discusses the results and the economic and sensitivity analyses, of applying the proposed optimization method to an actual customer in Ontario. Finally Section V highlights the main conclusions and contributions of this paper.

II. BACKGROUND

A. CAES Overview

CAES is a type of storage technology that uses off-peak electric energy to compress air, and store it in a high-pressure storage reservoir, which is then released during peak-load periods to drive a turbine generator to produce electricity. CAES can use different reservoirs to store the compressed air such as existing underground geological formations such as salt mine and hard-rock formations; porous rock and saline aquifers or depleted gas fields are ideally cost-effective storage mediums for large-scale CAES application [7].

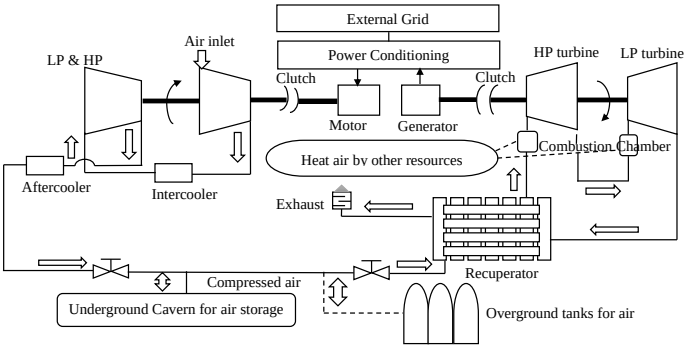


Fig. 1. Basic components of a CAES system [6].

The schematic diagram of a CAES system is illustrated in Fig. 1, and ideally consist of the following main components [7], [8]: compressors, expanders, air reservoirs, combustor, motor, generator, controlling system, and other auxiliary equipment, such as fuel tanks and pipe connection. A CAES plant operates in two different modes, namely, compression and expansion, and these modes can occur independently or simultaneously depending on the plant type. In the compression mode, off-peak low-cost electricity is used to run a chain of compressors which injects air into the reservoir at high pressure. The compressed air is stored at the temperature of the surrounding formation, and a regulating valve is used to throttle the compression pressure down to actual cavern pressure; intercoolers and an aftercooler are used to increase the efficiency in the compression stage. During the expansion stage, pressurized air is released from the reservoir and used to operate the gas turbine generator which produces electricity, using either diabatic or adiabatic approaches.

B. Ontario Electricity Pricing

In Ontario, the fixed prices paid to generators are recovered from two market-based components: the Hourly Ontario Energy Price (HOEP), and the Global Adjustment (GA) [9]. The GA is a payment that makes up the difference between the wholesale market price (HOEP), and the fixed contract rates in relation to the renewable sources Feed-in Tariff program, including the Ontario conservation costs, the expansion of gas capacity, and the nuclear power refurbishment programs [9]. The GA, therefore, has an inverse relationship with the HOEP and can be negative or positive depending on whether the HOEP for the generators is higher or lower than the guaranteed fixed rates. The allocation of the GA cost between Class A (large industrial customers) and Class B (residential customers) are not even, being charged at different rates. Customers participating in the ICI program are referred to as Class A. Their share of the GA costs are assessed based on the percentage their consumption contributes to the top five system peaks during the predetermined base period (May

1 - April 30), and their percentage of total GA costs are charged through the next billing period (July 1 - June 30). At the end of the base period, a peak demand factor (PDF) of the customer is determined by dividing the sum of its load demand with the sum of Ontario's system-wide demand during the five coincident peak (5cp) hours. This factor is used to multiply the total monthly Ontario GA cost to obtain the customer's monthly GA charge for the billing cycle. All electricity ratepayers in the province of Ontario pay the GA, even if it is not stated on the bill; for the residential and small commercial customers, the GA is embedded in their Time-of-use and Tiered Tariffs which is determined by the Ontario Energy Board [9].

III. MATHEMATICAL MODEL

The objective of the proposed SS-CAES system operation model is to minimize the electricity cost and the CAES system operation cost incurred by the industrial customer. Thus, an optimization problem is formulated considering a given capacity of SS-CAES, to determine the optimal charging/discharging decisions of the SS-CAES and energy purchase/consumption schedules of the customer, over a given time horizon. The flowchart in Fig. 2 summarizes the modeling framework to achieve a peak load reduction for electricity cost saving in an industrial facility with a behind-the-meter SS-CAES facility.

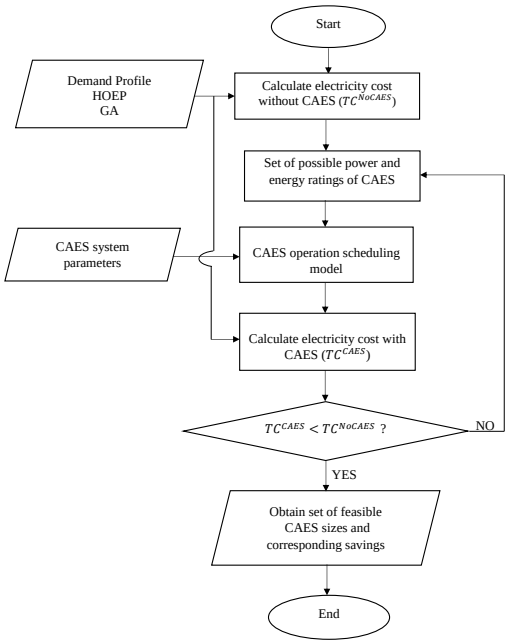


Fig. 2. Proposed optimization process flow diagram.

The base-case cost, without CAES, of the industrial customer comprises the energy cost (EC) and the GA charge (GA), which are estimated using the customer's load data, the HOEP, and Ontario's monthly GA obtained from the IESO website [9]. It is considered that CAES is deployed to shave the demand during the 5cp hours and also to reduce the hourly energy drawn from the grid. Different sets of power and energy ratings of the SS-CAES are considered. Thus a pair of power and energy rating of SS-CAES is considered a feasible set if the total cost of the industrial customer with CAES (TC^{CAES}) is lower than its total cost without CAES (TC^{NoCAES}). The obtained savings for each set of feasible SS-CAES ratings are used for economic evaluation and sensitivity analysis.

For the base-case, the objective of the optimization model is to minimize the total cost of the customer without the CAES installation, given as:

$$TC^{NoCAES} = EC^{NoCAES} + GA^{NoCAES} \quad (1)$$

where EC^{NoCAES} is the cost of energy consumed by the customer over the given time horizon (1 year) at the corresponding energy price, and is given as follows:

$$EC^{NoCAES} = \sum_{d=1}^{365}\sum_{h=1}^{24} PD_{d,h} Ep_{d,h} \quad (2)$$

The component GA^{NoCAES} is determined from the customer's contribution to the top five Ontario peak load hours, and can be expressed as:

$$GA^{NoCAES} = \sum_{5cp=1}^{5} \frac{PD_{d,h}}{OND_{d,h}} \sum_{m=1}^{12} OMGAC_m \quad (3)$$

In (2) and (3), $PD_{d,h}$ is the power demand of the customer at hour h of day d to meet its energy demand; $Ep_{d,h}$ is the corresponding hourly energy price, which is assumed same as the HOEP; $OND_{d,h}$ represents the total Ontario system demand at the 5cp hours; and $OMGAC_m$ is the monthly Ontario-wide total GA cost, which varies from month to month depending on whether the HOEP increased or decreased, as these two are inversely related [9]. The first term of (3) denotes the customer's PDF obtained from its load contribution to the Ontario's 5cp hours during the 12 month base period (May 1 to April 30), and is applied in the billing period (July 1 to June 30) to determine the customer's monthly GA charge.

To determine the impact of deploying CAES on the total annual electricity bill savings, the optimization model then minimizes the total annual cost of the industrial customer, defined as:

$$TC^{CAES} = EC^{CAES} + GA^{CAES} + SVOMC + SFOMC \quad (4)$$

where:

$$EC^{CAES} = \sum_{d=1}^{365}\sum_{h=1}^{24} Pgrid_{d,h} Ep_{d,h} \quad (5)$$

$$GA^{CAES} = \sum_{5cp=1}^{5} \frac{Pgrid_{d,h}}{OND_{d,h}} \sum_{m=1}^{12} OMGAC_m \quad (6)$$

$$SVOMC = \sum_{d=1}^{365}\sum_{h=1}^{24} (VOMC_{comp} P_{d,h}^{Ch} + VOMC_{exp} P_{d,h}^{DCh}) \quad (7)$$

$$SFOMC = CAPEX(FOMC) \quad (8)$$

In (5) and (6), $Pgrid_{d,h}$ is the power drawn by the customer from the grid to meet its energy demand and charge the CAES system when necessary, since the CAES facility is behind the customer's meter.

The $SVOMC$ component comprises only the variable operation and maintenance (O&M) cost during charging and discharging operation of the CAES. Another important cost metric considered for the economic analysis of a CAES project is the annual fixed O&M cost per year ($SFOMC$). According to consultations with industry partners, a good general starting point for the ($FOMC$) is between 1% and 1.5% of the capital cost ($CAPEX$). Thus, for the current work, the $FOMC$ of the CAES project is considered to be 1.5% of the $CAPEX$.

A. Model Constraints

1) Demand-Supply Balance: At each time interval, the customer's load is met by the power from the grid supply and the power discharged from the CAES, when it is operating in discharging mode as follows:

$$Pgrid_{d,h} + P^{DCh}_{d,h} = PD_{d,h} \qquad \forall\ d,h \quad (9)$$

and in charging mode:

$$Pgrid_{d,h} - P^{Ch}_{d,h} = PD_{d,h} \qquad \forall\ d,h \quad (10)$$

where, $Pgrid_{d,h} \leq Pgrid^{max} \quad \forall\ d,h$ is used to to represent the grid supply constraint, which is typically governed by the substation transformer capacity. Note that in charging mode in (10), SS-CAES appears as an additional load of the customer.

2) Coordination of Charging and Discharging: There is a need to ensure that the charging and discharging operation of the CAES system does not occur simultaneously; accordingly:

$$U^{Ch}_{d,h} + U^{DCh}_{d,h} = 1 \qquad \forall\ d,h \quad (11)$$

3) CAES Power Capacity: The charging and discharging power drawn by the SS-CAES is constrained by the compressor/expander minimum and maximum limits, respectively, as follows:

$$P^{min}_{comp} U^{Ch}_{d,h} \leq P^{Ch}_{d,h} \leq P^{max}_{comp} \qquad \forall\ d,h \quad (12)$$

$$P^{min}_{exp} U^{DCh}_{d,h} \leq P^{DCh}_{d,h} \leq P^{max}_{exp} \qquad \forall\ d,h \quad (13)$$

4) CAES Energy Capacity: The energy stored or discharged at each time interval is constrained by the allowable state-of-charge (SOC) limits of the CAES, as follows:

$$E^{min} \leq E_{d,h} \leq E^{max} \qquad \forall\ d,h \quad (14)$$

where $E^{min}_{d,h}$ is set to zero, which is different than a battery energy storage, while $E^{max}_{d,h}$ is the maximum energy capacity of the cavern. The initial SOC of the CAES is assumed to be 50% of the installed CAES energy capacity, i.e.,

$$E_{1,1} = 0.5E^{max} \quad (15)$$

5) CAES Energy Balance: The amount of compressed air in the storage is expressed in terms of the electrical output energy, i.e., in MWh rather than compressed air volume and pressure. The energy stored in the cavern of the CAES system at an interval is dependent on the stored energy from previous interval and the energy added when charging or depleted when discharging, subject to the respective efficiency of the compressor (η_{comp}) and expander (η_{exp}), respectively. If the energy loss in the cavern is neglected, one has:

$$E_{d,h} = E_{d,h-1} + P^{Ch}_{d,h}\eta_{comp} - \frac{P^{DCh}_{d,h}}{\eta_{exp}} \qquad \forall\ d,h \quad (16)$$

6) Annual Maintenance: The CAES should be scheduled for annual maintenance, and thus, a downtime constraint is imposed on the CAES unit to account for scheduled maintenance, as follows:

$$\sum_{d=1}^{365}\sum_{h=1}^{24}(U^{Ch}_{d,h} + U^{DCh}_{d,h}) \leq 8760(1 - MDT) \quad (17)$$

where MDT is the minimum downtime as a fraction of total hours in a year.

The proposed model given by (1) to (17) is a Mixed Integer Linear Programming (MILP) problem and is implemented in GAMS [10], a high-level modeling system for solving mathematical programming problems, and solved using the CPLEX 12.5 solver.

IV. Results and Discussion

The aforementioned model is applied to a load profile of a real Class A customer in Ontario, to determine the possible cost reduction resulting from deploying an SS-CAES system at the customer's facility to reduce the load demand and energy drawn from the grid. The peak demand of the customer is 14.27 MW; however, this peak demand occurrs for less than 2% of the hours in the year. Furthermore, only for about 10% of the hours, the facility demand was more than 11 MW. This observation is vital to avoid over sizing the CAES, which would increase the investment cost. The HOEP and monthly GA for the considered period is obtained from the IESO website [9].

A. SS-CAES Parameters and Assumptions

Different sizes of CAES were considered at an increment of 2 MW up to 10 MW, based on the facility's peak load, and for various discharge hours, depending on the power capacity to study the impact of energy capacity. The 5cp days and hours are known apriori, and the customer's load is considered fixed for the planning horizon. For the sake of simplicity, the compressor power and generator power ratings are the same. The O&M cost is taken from [11], and the efficiency of the CAES plant are obtained from [4].

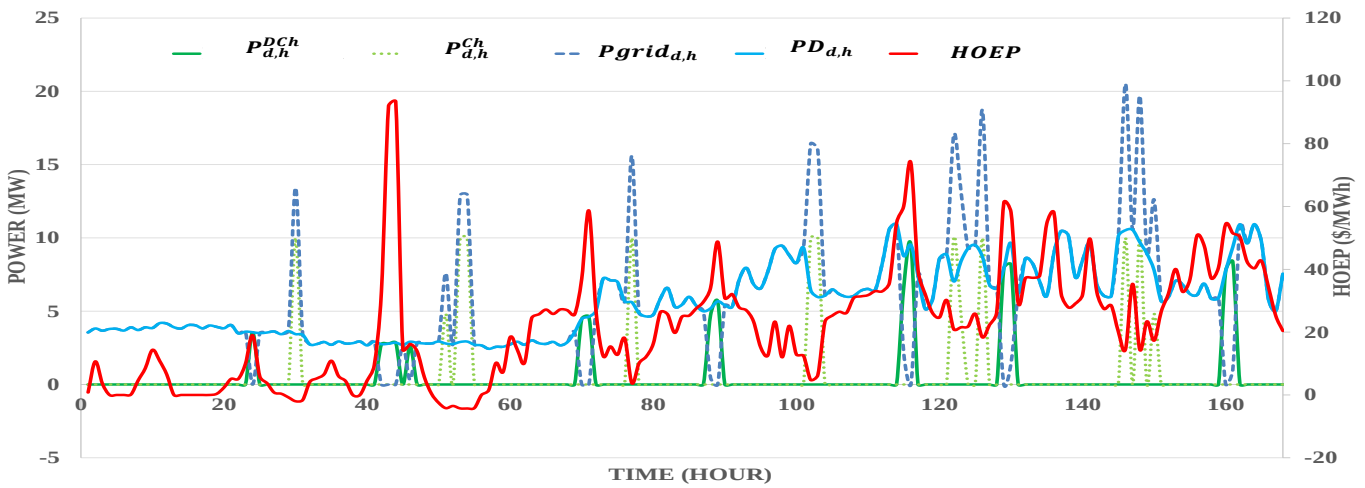


Fig. 3. One week operation of the CAES dispatch model.

The results obtained indicate that in Ontario, Canada, a Class A customer could save up to a minimum of $970,742 in electricity cost per year for a CAES size of 2 MW/4 MWh, with increasing savings as the size increases. In Fig.3, a 1-week dispatch of the CAES operation model is illustrated. Note that the CAES system is able to respond to changing electricity prices, charging at low prices and discharging during high price hours, as expected.

This results show that CAES sited behind-the-meter is a viable option for a real customer participating in the ICI program to reduce its electricity costs. However, determining the feasible sizes requires an economic analysis taking into account the capital cost to determine the worth of the investment, as discussed next.

B. Economic and Sensitivity Analysis

This section examines the economic feasibility and risks over the long-term of a SS-CAES plant installed at an actual customer's facility for load management applications. Different CAES sizes, electricity price (GA), CAES unit costs, and life cycle times are considered for sensitivity analysis to evaluate how the revenue of the investor would be impacted by the changes.

The annual savings in electricity cost accrued from the installation of an SS-CAES system to shave the facility's load demand is given as follows:

$$S_y = TC_y^{NoCAES} - TC_y^{CAES} \tag{18}$$

where S_y is the annual savings of the facility. The internal rate of return (IRR) for the investment in CAES system can be obtained by solving the following equation [12]:

$$\sum_{y=1}^{N} \frac{S_y}{(1 + IRR)^N} - CAPEX = 0 \tag{19}$$

where N is the CAES project life in years and $CAPEX$ is the initial capital cost of the SS-CAES system, which varies with scale, mode of storage medium, and location [4]. The range of unit capital costs considered in this research is adopted from Hydrostors AA-CAES project as 1,500 to 3,000 $/kW [4], which reflects all costs of the CAES system, including its various components, implementation and deployment, with respect to power and not energy due to the relevance of the former for the application being considered, as demonstrated by the results presented and discussed in this section. The upper value of the cost is considered here for the lower range CAES capacity (2 MW), and the lower cost value for the higher CAES size (10 MW). Assuming a linear relationship between $CAPEX$ and the CAES unit size, the intermediate costs can be estimated. It should be mentioned that accurate estimation of the costs of a CAES systems is challenging, as these are site-specific and depend largely on local environmental constraints of the reservoir [13]. Note that the costs considered here are larger than in [6], and are based on information provided by the developers of an SS-CAES facility of comparable size and in a similar location to the system considered in this work.

In practice, when planning investment projects, companies often set a minimum acceptable rate of return (MARR) to determine the minimum acceptable IRR of the investment to be worthwhile. Technically, any project with an IRR that exceeds the MARR is deemed a profitable one [12]. MARR vary from project to project and depends on different factors such as project risk, investment opportunities, and limits on available capital [12]. A 10% MARR is typically considered for low risk investments [14]; therefore, a moderate 14% MARR is considered for the project analyzed in this work, and the results obtained are shown in Fig.4. Note that CAES systems with higher power ratings, even for shorter project life cycles, yield a high IRR. Observe that, a nominal 2 MW CAES system with a project life of 25 years has an IRR of 15%, which can be considered to be an acceptable proposition. The linearly increasing trend of the IRR from lower CAES ratings to higher ones can be associated with the corresponding assumption of

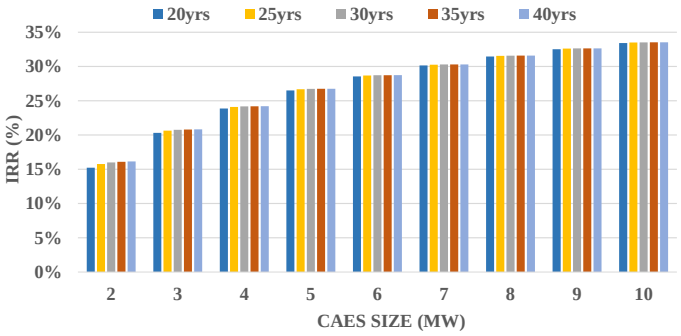


Fig. 4. IRR results of the detailed economic analysis

linear capital cost variation with size.

From the presented economic analysis, it can be observed that the IRRs for behind-the-meter SS-CAES are affected by factors such as the capacity of the CAES system. Also, since SS-CAES projects are at the pilot stage, economic uncertainties are relatively high, and therefore, it is necessary to perform a sensitivity analysis to understand the significance of the various parameters affecting CAES investment viability.

1) Sensitivity to CAES Capacity: The energy capacity of a 5 MW CAES system is varied over a range of 10-30 MWh to gain insight on how the cost reduction can be impacted by the size of the storage medium. Fig.5 shows that doubling the energy size only results in less than 1.1% savings in the electricity cost. This is because the cost savings are primarily dependent on the GA reduction, which depends on th CAES power discharge rating. Furthermore, from the economic anal-

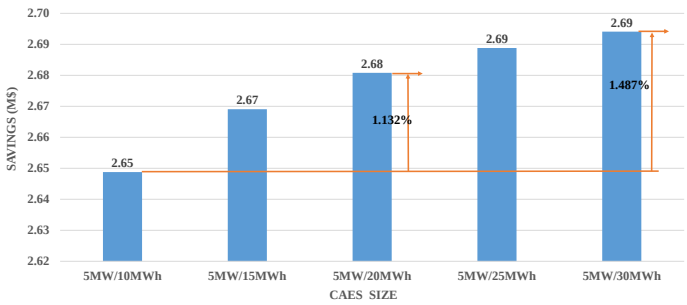


Fig. 5. Impact of CAES energy capacity on cost reduction.

ysis of Fig.4, observe that the IRRs are significantly dependent on the CAES power capacity. Therefore, it can be deduced that the power capacity of the CAES has a higher impact on the customer's load profile in Ontario than its energy capacity. Accordingly, for subsequent studies, only the power capacity of the CAES is varied for 2 hours fixed discharge duration.

2) Sensitivity to GA: As stated earlier, GA charge is the major driver of the rising cost of electricity for C&I customers in Ontario. Hence, sensitivity studies are carried out by considering a reduction in the GA charge, in steps of 5% from the nominal, and the results are shown in Figs. 6 to 8. Note that even for a 10% reduction in GA charge, the IRRs of all the considered CAES sizes and life cycles are above 14%. For a 15% reduction in GA, the 2 MW/4 MWh SS-CAES system in all the years considered yields an IRR less than 14%. Furthermore, note that for CAES capacities of 3 MW and above, for all life cycles considered, the IRRs are all above 15%.

It should be mentioned that the HOEP does not significantly impact the IRR, especially compared to the impact of GA or other parameters considered. This is because the HOEP is a relatively small fraction of the commodity cost of electricity in Ontario, Canada, with the primary driver for the rising prices of electricity in Ontario being the GA component and not the HOEP. Therefore, in the presented work, sensitivity studies considering HOEP have not been presented.

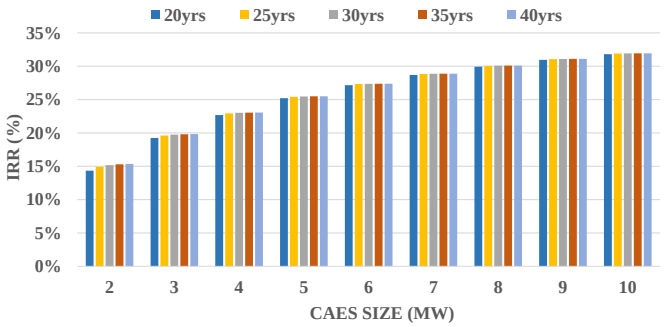


Fig. 6. Variation of IRR with CAES size, 5% reduction in GA

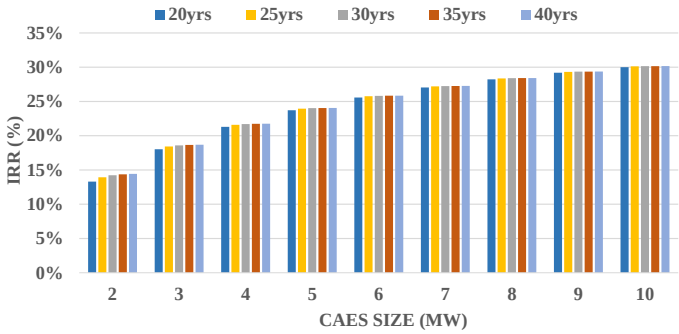


Fig. 7. Variation of IRR with CAES size, 10% reduction in GA

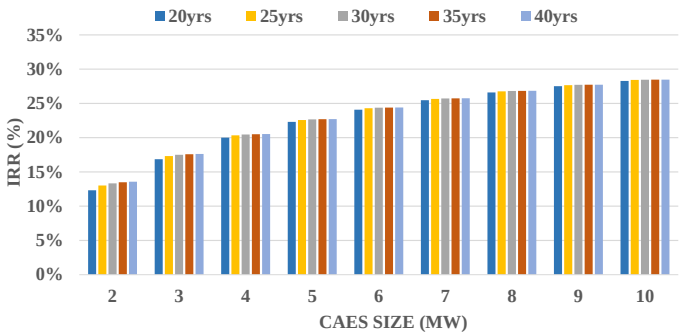


Fig. 8. Variation of IRR with CAES size, 15% reduction in GA

3) Sensitivity to CAES Capital Cost: There are uncertainties surrounding the capital cost of SS-CAES unit due to the limited number of such projects in existence, and the uniqueness of each project possible design. In the current research work, it is assumed that the customer has an existing well/cavern which can be re-purposed for air storage, which could significantly reduce the capital cost of the CAES project [7]. Most of the available data on CAES unit cost are specifically for large-scale CAES projects; hence taking into account economies of scale, smaller sized CAES systems can be expected to have a higher unit cost. To account for cost uncertainties, the CAES unit cost is varied here by +$500/kW. Thus, as can be seen from the results presented in Figs. 9 to 10, the IRRs linearly decrease as the unit capital cost of the CAES increases. Again, as per the assumed MARR, 3 MW/6 MWh CAES capacity and above can be considered to be economically attractive if the unit cost is below the 2,000 - 3,500 $/kW range. For a 3,000-4,500 $/kW unit cost range, investment in the SS-CAES makes economic sense when the system capacity exceeds 6 MW/12 MWh to attain an IRR of 14%.

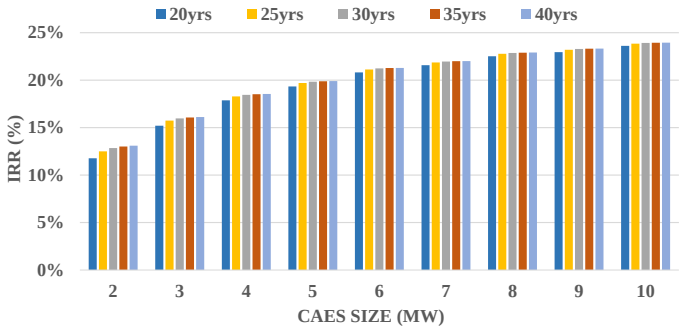


Fig. 9. Variation of IRR with CAES size for a CAPEX range of 2,000-3,500 $/kW

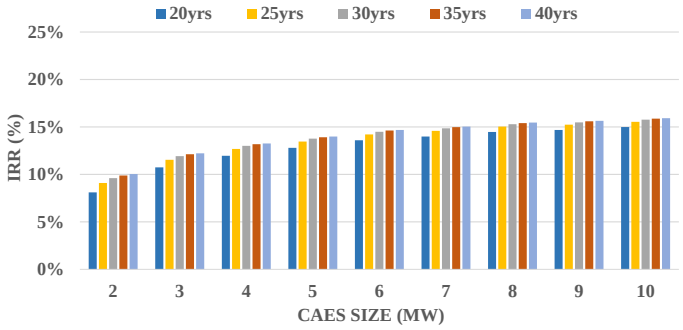


Fig. 10. Variation of IRR with CAES size for a CAPEX range of 3,000-4,500 $/kW

V. Conclusions

In this paper, a mathematical operation model is proposed to manage the load of a real industrial customer's facility equipped with a behind-the-meter SS-CAES. The presented optimization model determined the minimum electricity costs, the SS-CAES energy output, and the corresponding charging and discharging decisions for the facility. To examine the economic feasibility and risks over the long-term of a SS-CAES plant installed at an actual customer's facility for load management applications, different CAES sizes, electricity prices, CAES unit costs, and life cycle times were considered for sensitivity analysis to evaluate how the revenue of the investor would be impacted by the changes. The presented results show that SS-CAES installed behind-the-meter on the facility's premise for reducing the electricity cost of the customer provides a viable economical solution under the current Ontario's electricity market structure. A larger discharge power capacity (kW) of the SS-CAES facility makes more economic sense than energy capacity (kWh), since the demand charge (Global Adjustment or GA in Ontario [2]) of such customers are based on their load contribution during the top peak hours. It is shown that the capital cost of the CAES project and the demand charge are the most influential parameters that determine the economic feasibility of behind-the-meter SS-CAES. Given the restructuring currently being considered of Ontarios electricity market, to address the issue of high prices, particularly the GA, it would be relevant to investigate the impact of these reforms on investments in behind-the-meter SS-CAES once these modifications are announced.

References

[1] EnergyWatch, "Peak Load Management Strategies," 2018. [Online]. Available: https://energywatch-inc.com/peak-load-management-strategies/

[2] IESO, "What is Global Adjustment?" [Accessed on 2019/02/25]. [Online]. Available: http://www.ieso.ca/en/Learn/Electricity-Pricing/What-is-Global-Adjustment

[3] M. Uddin *et al.*, "A Review on Peak Load Shaving Strategies," *Renewable and Sustainable Energy Reviews*, vol. 82, pp. 3323 – 3332, 2018.

[4] Hydrostor, "Advanced Compressed Air Energy Storage," presented at the Australian Energy Storage Association Conference, Adelaide, SA, 2018, [Accessed on 2019/01/15]. [Online]. Available: https://australianenergystorage.com.au/wordpress/wp-content/uploads/2018/06/1145-Thur-CR-Norman.pdf

[5] C. C. Anierobi, "Behind-the-Meter Compressed Air Energy Storage Feasibility and Applications," Master's thesis, University of Waterloo, Ontario, Canada, May 2019.

[6] J. Wang *et al.*, "Overview of Compressed Air Energy Storage and Technology Development," *Energies*, vol. 10, pp. 1 – 22, July 2017.

[7] X. Luo, J. Wang, M. Dooner, and J. Clarke, "Overview of Current Development in Electrical Energy Storage Technologies and the Application Potential in Power System Operation," *Applied Energy*, vol. 137, pp. 511 – 536, 2015.

[8] L. Li, W. Liang, H. Lian, J. Yang, and M. Dusseault, "Compressed Air Energy Storage: Characteristics, Basic Principles, and Geological Considerations," *Advances in Geo-Energy Research*, vol. 2, pp. 135 – 147, March 2018.

[9] IESO, "Guide to Wholesale Electricity Charges," [Accessed on 2019/02/25]. [Online]. Available: http://www.ieso.ca/Sector-Participants/Settlements/Guide-to-Wholesale-Electricity-Charges

[10] R. E. Rosenthal, "GAMS - A User's Guide," May 2015. [Online]. Available: http://www.gams.com/dd/docs/bigdocs/GAMSUsersGuide.pdf

[11] A. A. Akhil *et al.*, "Electricity Storage Handbook," DOE/EPRI in Collaboration with NRECA, United States, September 2016.

[12] K. K. Humphreys, *Jelen's Cost and Optimization Engineering*, 3rd ed. New York: McGraw-Hill, 1991.

[13] IRENA, "Electricity Storage and Renewables: Costs and Markets to 2030," *Abu Dhabi.: International Renewable Energy Agency*, 2017.

[14] D. N. Merino and H. J. Lang, *The Selection Process for Capital Projects*. New York: J. Wiley & Sons, 1993.